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April 30, 2004

California Energy Commission
Re: Docket No. 03-IEP-01 and 03-RPS-1078
Docket Unit, MS-4
1516 Ninth Street
Sacramento, CA 95814-5504

In the Matter of:	Docket 03-IEP-01 and 03-RPS-1078
Informational Proceeding and Preparation of the 2004 **Integrated Energy Policy Report (IEPR) Update**	Notice of Committee Workshop on Accelerated Renewable Energy Development

Dear Energy Commissioners and Staff:

Calpine Corporation ("Calpine") appreciates the opportunity to submit the following comments to the May 4, 2004, Committee Workshop on Accelerated Renewable Energy Development.[1] Calpine's comments are as follows:

Accelerated RPS Goals Beyond 2010

1. Should the state pursue additional renewable development beyond 20 percent of retail sales by 2010 through either mandates or incentive structures?

   Calpine is the largest generator of renewable energy in California and believes that the pursuit of additional renewable development is a laudable goal, however policy makers need to be realistic. In its November 2003 Renewable Energy Development Report, the Energy Commission identified the need for an additional 24,800 gigawatt-hours per year of renewable energy beyond the current installed capacity in order to meet the 20 percent target by 2010. In order to meet this target, the state's investor-owned utilities, municipal utilities, energy service providers and other energy retailers will need to contract for 3,000 mw of new baseload renewable facilities, or 10,000 mw of wind facilities, or some combination. Given the time required to permit, develop, finance and construct projects, these contracts will need to be in place either this year or next. Frankly, we do not see that happening. Progress to date suggests that the 20 percent target by 2010 will not be met.

[1] The Commission's April 20, 2004 Notice of Committee Workshop on Accelerated Renewable Energy Development requested workshop comments by interested parties by April 30, 2004.

Calpine recommends that the state find ways to expedite the current process rather than establish new goals in the more distant future. With regard to incentives, the potential extension and expansion of the federal production tax credit to cover all renewable technologies will represent a substantial incentive, if it comes to pass.

2. What benefits and barriers are there associated with accelerated renewable development beyond 2010?

   The benefits associated with renewables are well known by the Energy Commission and include improved air quality, stable prices, use of indigenous resources, and economic development. One of the barriers to renewable development is the complexity of the RPS legislation and its implementation. It will have taken 18 months from the time that SB 1078 became effective until the first renewable solicitation takes place under the law. The delay and the resulting lack of power purchase agreements is the largest barrier to accelerated renewable development.

   A second barrier resulting from the legislation is the arcane set of eligibility requirements that restrict many cost effective renewable projects from competing in the RPS. As a geothermal producer, Calpine has focused on the restriction that prevents existing geothermal facilities from being eligible for the RPS. The restriction was put in place at the request of other market participants out of fear that existing geothermal would out-compete their resources for power purchase agreements. Calpine has proposed that the RPS law be amended to allow this restriction to sunset within a few years, and would like the Energy Commission to support the amendment. [2]

   An additional barrier to accelerated renewable development is the considerable length of time that it takes to permit a renewable project in California. Regulations should be written to expedite the environmental review and permitting of all renewables in California to achieve the RPS goals.

3. How and when should the state's accelerated goals be articulated, implemented, and evaluated?

   Calpine recommends that the state focus on achieving the 2010 goal before articulating grander goals for the distant future. If by 2008 it appears that the state's load serving entities will meet the 20 percent by 2010 goal, the state could develop additional targets.

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[2] Calpine's proposed amendment (underlined) to subsection 399.12(a)(1)(2) of the Public Utilities code:

(2) A geothermal generation facility originally commencing operation prior to September 26, 1996, shall be eligible for purposes of adjusting a retail seller's baseline quantity of eligible renewable energy resources except for output certified as incremental geothermal production by the Energy Commission, provided that the incremental output was not sold to an electrical corporation under contract entered into prior to September 26, 1996. For each facility seeking certification, the Energy Commission shall determine historical production trends and establish criteria for measuring incremental geothermal production that recognizes the declining output of existing steamfields and the contribution of capital investments in the facility or wellfield. This subsection 399.12(a)(1)(2) in its entirety shall not apply to geothermal generation purchased by an electric service provider or a community choice aggregator, and shall terminate on January 1, 2008.

Re-calibration of Specific Utility Goals

1. Should RPS obligations differ by utility or retail seller, or should the obligations remain equal statewide as in current law?

   Calpine recommends that each load serving entity achieve an equal percentage of its retail sales from renewables as is provided in current law. If customers of energy service providers (ESP) and community choice aggregators (CCA) are required to pay an exit fee to a utility that is partially attributable to renewable power, then that ESP or CCA should receive credit for that power towards its RPS requirement.

   Additionally, we recommend that ESPs and CCAs be able to comply with their RPS requirements by acquiring renewable power or RECs on a term equal to their power sales commitments. For example, if an ESP is selling power to a retail customer under a two year contract, that ESP should be able to acquire renewable power or RECs for two years, rather than the 10 year minimum term required of utilities.

2. How should the varying amount of renewable energy available within each utility area be taken into account?

   There is no need to take the renewable energy available in each utility area into account. Utilities can purchase renewable energy located in other utilities' territories or from out of state.

3. How should the transmission infrastructure, including utilization of existing transmission capability within and among utility areas, be taken into account?

   Sellers should be allowed the flexibility to arrange creative solutions to transmission problems, without the need to purchase firm transmission rights. A utility should be able to contract with a project located in a different utility's service territory, pay for the power based on meter readings at the project's busbar, and take delivery in its own service territory without the seller being required to demonstrate a wheeling path. The seller could accomplish delivery (1) through a power swap, (2) by scheduling a like amount of power in the opposite direction, or through various other methods. Additionally, sellers should also be able to utilize shaping and firming services, such as the BPA wind integration product to reduce transmission costs.

4. How should differential costs of resource development in relation to electricity rates in each area be taken into account?

   Consideration should be given to differential value of renewable projects depending upon their location rather than differential costs. For example, projects located in areas where generation is needed to either relieve congestion or for reliability purposes should command a higher price and be valued higher in the least cost/best fit evaluation than those in less desirable locations.

5. If differential targets make sense economically, should they be mandated or achieved through incentive structures? What mandates or incentive structures would you suggest?

   If differential targets make sense economically, then there should be no need to mandate them. Calpine has heard anecdotally that many load serving entities are interested in exceeding the 20 percent target, and for the time being we recommend that these accelerated goals be kept voluntary. One incentive structure that could help bring renewable projects on-line sooner is the establishment of an expedited permitting process.

<u>RPS As It Applies to Publicly Owned Electric Utilities</u>

We have no comment to this section.

<u>Tradable Renewable Energy Certificates</u>

1. What information is available or should be developed to provide a clear showing of the type stated above (from the CPUC June 19, 2003 decision)? What are the necessary features of a REC trading system?

   The use of RECs to satisfy the RPS requirements would benefit California citizens provided that they are coupled with in-state delivery requirements and are priced in a manner that insulates ratepayers from fossil fuel prices.

2. How could tradable RECs be used with in-state delivery requirements under the RPS? What benefits would their use provide in this context? What costs?

   Calpine supports the use of RECs to satisfy the RPS when used with in-state delivery requirements. RECs would come from eligible renewable facilities and could be coupled with brown energy and delivered to the purchasing utility, where they would then be extinguished. The benefits of using RECs include reduced transmission costs and better ability to shape power deliveries to meet the utilities requirements.

3. If a REC trading system is adopted, how should, if at all a market price referent be established for a REC-only transaction?

   There should not be a market price referent for a REC-only transaction.

4. If a REC trading system is adopted, how should, if at all, supplemental energy payments apply to REC-only transactions?

   Neither REC-only transactions nor RECs coupled with brown energy should be eligible for supplemental energy payments (SEPs). SEPs should only be paid to eligible renewable generators, not third parties. As we noted earlier in these comments, Calpine believes sellers should have the ability to make creative arrangements to deliver power from eligible facilities to the buyer's service territory. To the extent that an eligible renewable generator executes a contract with a California utility, and the energy purchased is based on meter readings at the project's busbar, the facility should be eligible for SEPs.

5. How is the ownership of RECs affected when public goods charge funds support the associated renewable energy in the form of supplemental energy payments or other state or federal incentives?

   Since supplemental energy payments will only be made to eligible projects that sell their power to California utilities, and since those utilities will require by contract that the RECs go to them, the answer is straight forward, the utilities get the RECs. With regard to other state or federal incentives, unless otherwise specified, the RECs stay with the generator.

Thank you for considering Calpine's comments. Please contact me if you have any questions regarding these issues.

Sincerely,

Jack Pigott
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